L A R E D O P E T R O L E U M

Fourth-Quarter & Full-Year 2018 Earnings Presentation

LAREDO PETROLEUM

Forward-Looking / Cautionary Statements

This presentation, including any oral statements made regarding the contents of this presentation, contains forward-looking statements as defined under Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements, other than statements of historical facts, that address activities that Laredo Petroleum, Inc. (together with its subsidiaries, the “Company”, “Laredo” or “LPI”) assumes, plans, expects, believes, intends, projects, estimates or anticipates (and other similar expressions) will, should or may occur in the future, including, but not limited to, the share repurchase program, which may be suspended or discontinued by the Company at any time, are forward-looking statements. The forward-looking statements are based on management’s current belief, based on currently available information, as to the outcome and timing of future events.

General risks relating to Laredo include, but are not limited to, the decline in prices of oil, natural gas liquids and natural gas and the related impact to financial statements as a result of asset impairments and revisions to reserve estimates, the increase in service costs, hedging activities, possible impacts of pending or potential litigation and other factors, including those and other risks described in its Annual Report on Form 10-K for the year ended December 31, 2017, and those set forth from time to time in other filings with the Securities Exchange Commission (“SEC”) including, but not limited to, its Annual Report on Form 10-K for the year ended December 31, 2018, to be filed with the SEC. These documents are available through Laredo’s website at www.laredopetro.com under the tab “Investor Relations” or through the SEC’s Electronic Data Gathering and Analysis Retrieval System at www.sec.gov. Any of these factors could cause Laredo’s actual results and plans to differ materially from those in the forward-looking statements. Therefore, Laredo can give no assurance that its future results will be as estimated. Laredo does not intend to, and disclaims any obligation to, update or revise any forward-looking statement.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

The SEC generally permits oil and natural gas companies, in filings made with the SEC, to disclose proved reserves, which are reserve estimates that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions and certain probable and possible reserves that meet the SEC’s definitions for such terms. In this presentation, the Company may use the terms “resource potential,” “estimated ultimate recovery” (“EURs”) or “type curve,” each of which the SEC guidelines restrict from being included in filings with the SEC without strict compliance with SEC definitions. These terms refer to the Company’s internal estimates of unbooked hydrocarbon quantities that may be potentially discovered through exploratory drilling or recovered with additional drilling or recovery techniques. “Resource potential” is used by the Company to refer to the estimated quantities of hydrocarbons that may be added to proved reserves, largely from a specified resource play potentially supporting numerous drilling locations. A “resource play” is a term used by the Company to describe an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section potentially supporting numerous drilling locations, which, when compared to a conventional play, typically has a lower geological and/or commercial development risk. “Estimated ultimate recovery,” or “EURs,” are based on the Company’s previous operating experience in a given area and publicly available information relating o the operations of producers who are conducting operations in these areas. Unbooked resource potential or EURs do not constitute reserves within the meaning of the Society of Petroleum Engineer’s Petroleum Resource Management System or SEC rules and do not include any proved reserves. Actual quantities of reserves that may be ultimately recovered from the Company’s interests may differ substantially from those presented herein. Factors affecting ultimate recovery include the scope of the Company’s ongoing drilling program, which will be directly affected by the availability of capital, decreases in oil, natural gas liquids and natural gas prices, well spacing, drilling costs and production costs, availability and costs of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals, negative revisions to reserve estimates and other factors as well as actual drilling results, including geological and mechanical factors affecting recovery rates. Estimates of EURs may change significantly as development of the Company’s core assets provides additional data. In addition, our production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases. “Type curve” refers to a production profile of a well, or a particular category of wells, for a specific play and/or area. In addition, the Company’s production forecasts and expectations for future periods are dependent upon many assumptions, including estimates of production decline rates from existing wells and the undertaking and outcome of future drilling activity, which may be affected by significant commodity price declines or drilling cost increases.

This presentation includes financial measures that are not in accordance with generally accepted accounting principles (“GAAP”), including Adjusted EBITDA. While management believes that such measures are useful for investors, they should not be used as a replacement for financial measures that are in accordance with GAAP. For a reconciliation of Adjusted EBITDA to the nearest comparable measure in accordance with GAAP, please see the Appendix.

FY-18 Highlights

~17% BOE YoY production growth

~19% Proved reserves YoY value increase to $2.1 B

~13% Organic proved developed reserves YoY volume growth

~14% Cash margin per BOE increase YoY[1]

~1.6x Net debt to Adjusted EBITDA[2]

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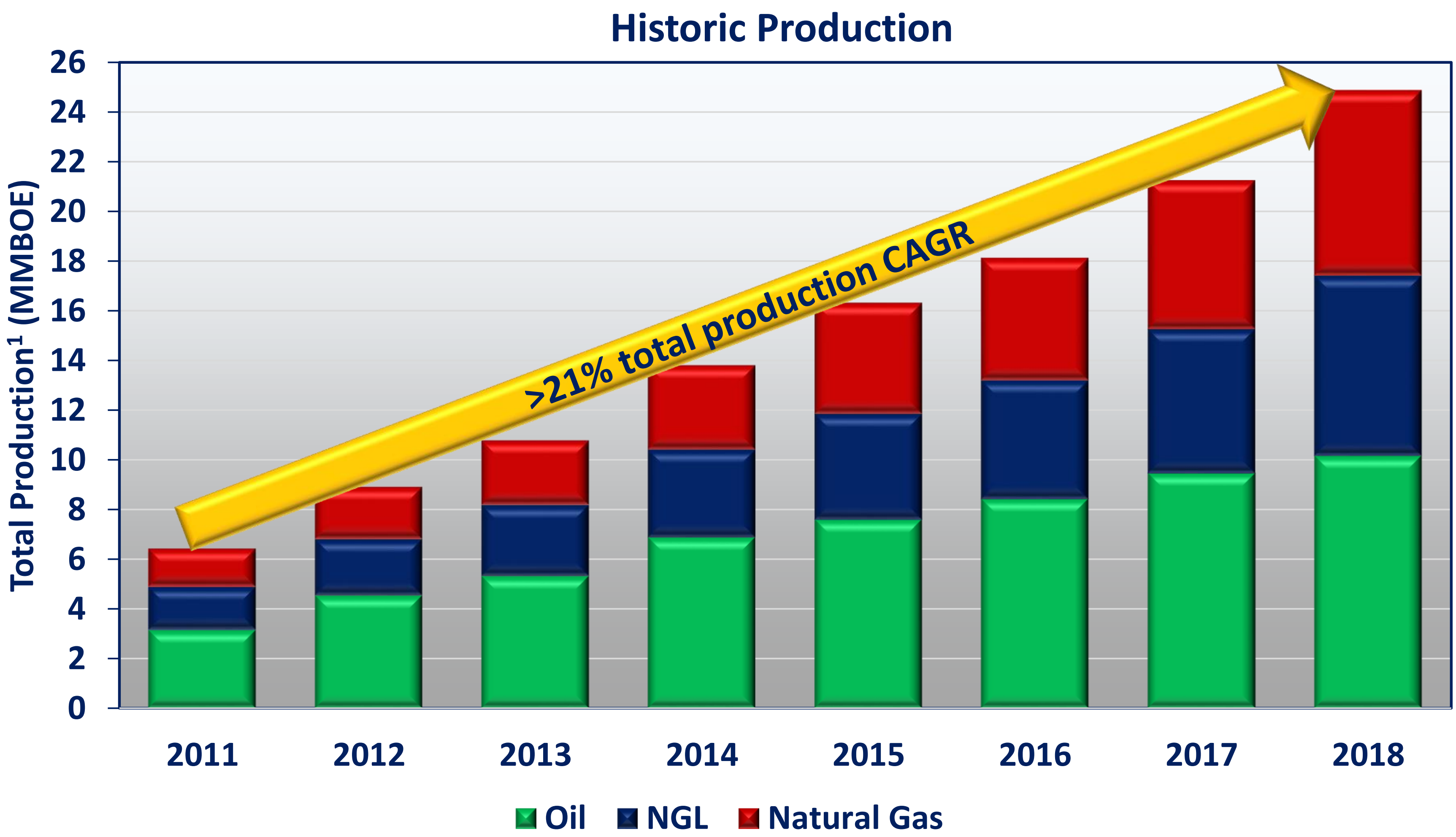
[1]See Appendix for an explanation of Cash Margin per BOE

[2]Net debt to Adjusted EBITDA is calculated as net debt as of 12/31/18 divided by FY-18 Adjusted EBITDA. Net debt as of 12/31/18 is calculated as the face value of long-term debt of $990 MM, reduced by cash on hand of $45 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA

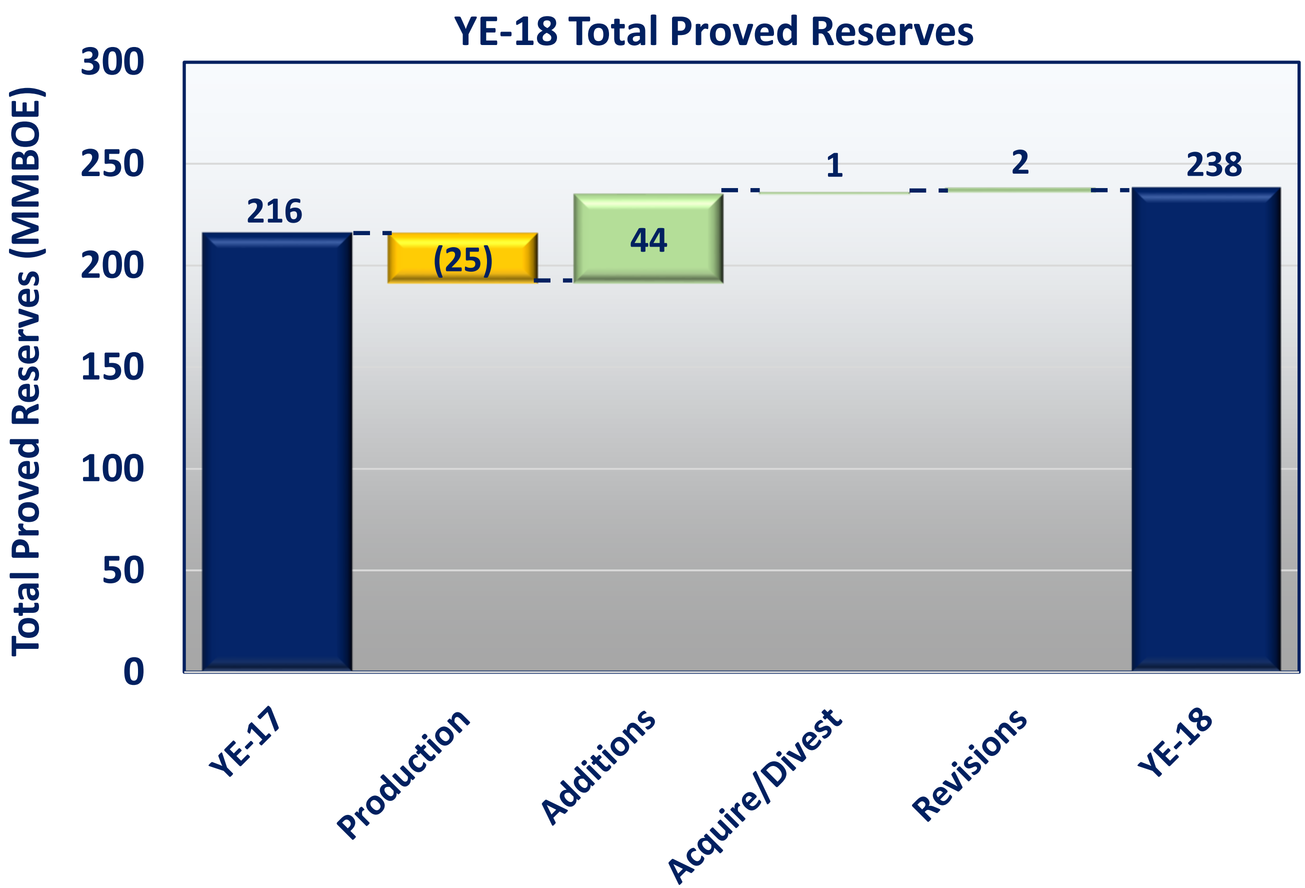
History of Consistent Production Growth

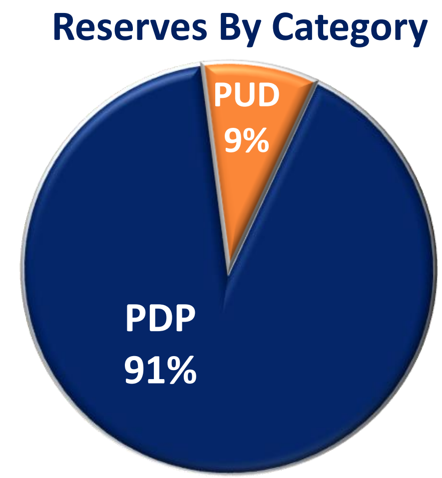


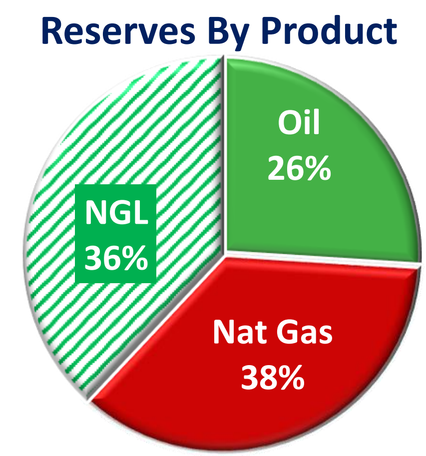
~17% YoY growth in FY-18 total production

[1] 2011 - 2014 results have been converted to 3-stream using actual gas plant economics. 2011 - 2013 results have been adjusted for Granite Wash divestiture, closed August 1, 2013

Organically Grew Total Proved Reserves In 2018



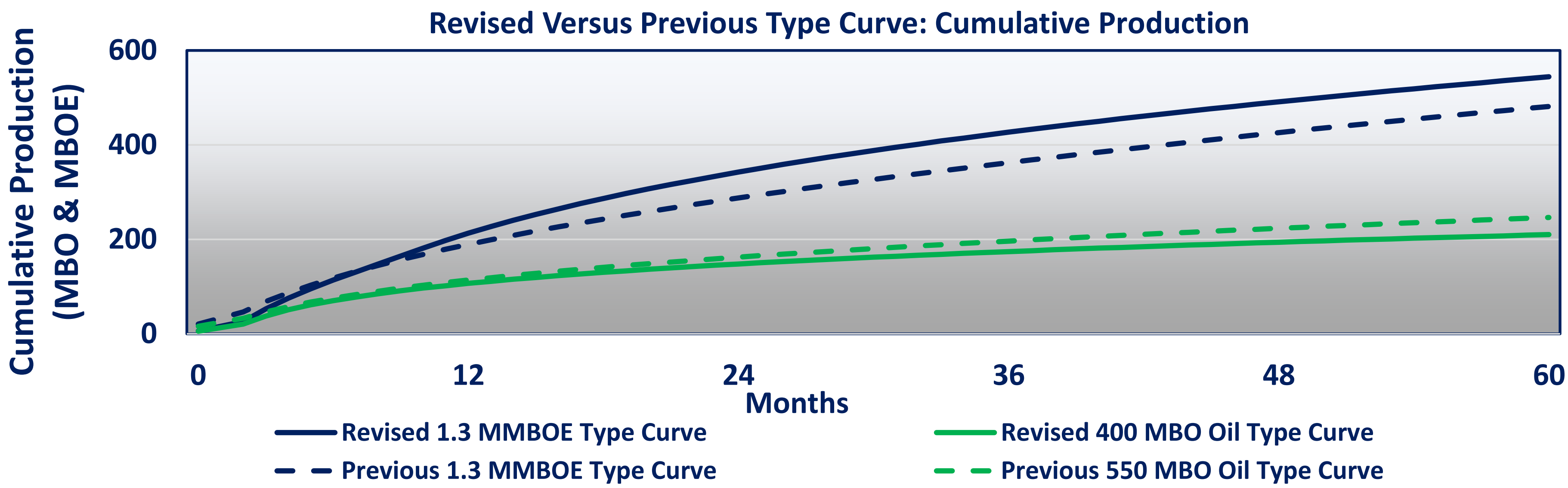




~19% YoY increase in total proved reserves value

Note: Based on YE-18 3-stream proved reserves, prepared by Ryder Scott. Reserves have been rounded to the nearest 1 MMBOE

Revised Type Curve Expected to Yield Similar Returns as Previous



Revised Type Curve: Production By Year			
Year	Oil (MBO)	Total (MBOE)	Oil Cut (%)
1	107	213	50%
2	41	130	32%
3	26	84	31%
4	20	64	31%
5	16	53	30%
5-Year Cumulative	210	544	39%

Previous Type Curve: Production By Year			
Year	Oil (MBO)	Total (MBOE)	Oil Cut (%)
1	114	189	60%
2	49	98	49%
3	34	75	46%
4	27	64	43%
5	23	55	41%
5-Year Cumulative	246	481	51%

Similar returns driven by accelerated natural gas & NGL recoveries

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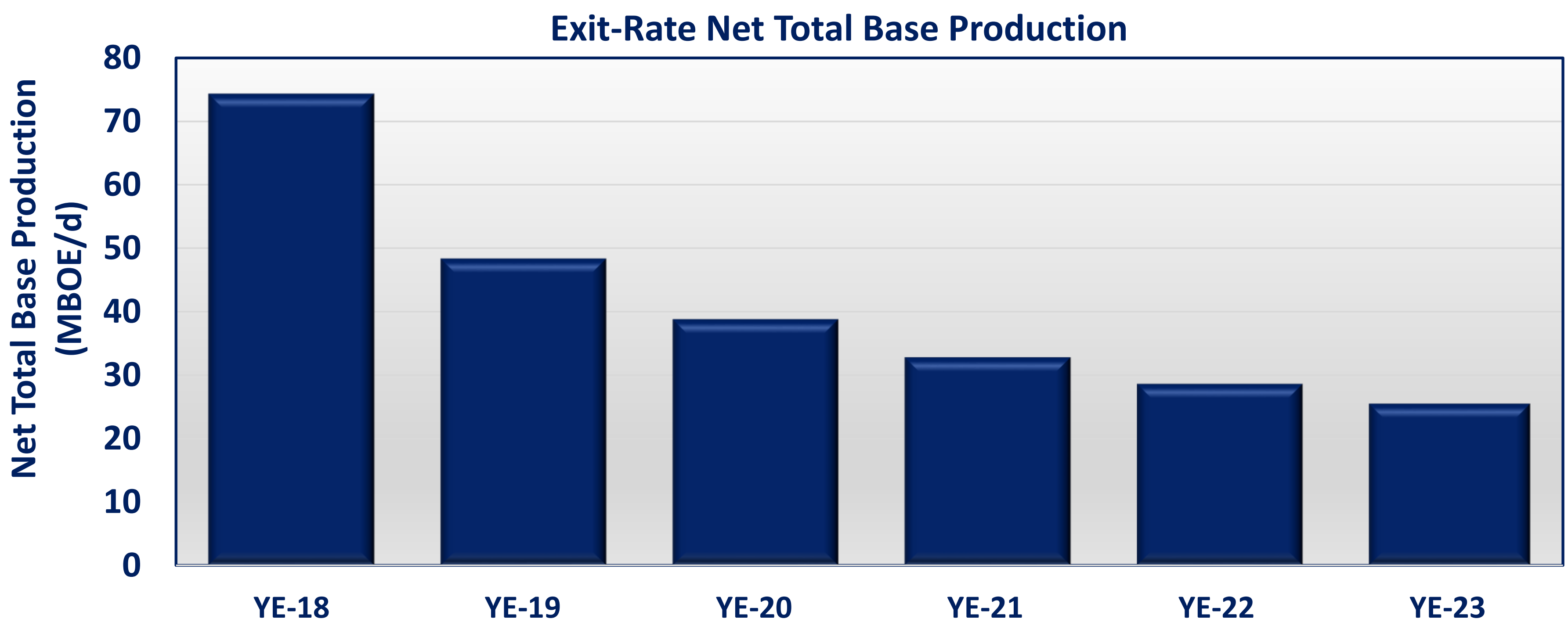
Note: Previous 1.3 MMBOE type curve included a 1.45 b-factor
Revised 1.3 MMBOE type curve includes a 1.20 b-factor
Table may not foot due to rounding

YE-18 Total PDP Reserves 5-Year Decline



	Year 1	Year 2	Year 3	Year 4	Year 5
Decline Rate	-35%	-20%	-15%	-13%	-11%

Natural gas and NGLs are exhibiting flatter declines, yielding shallower total decline rates than oil

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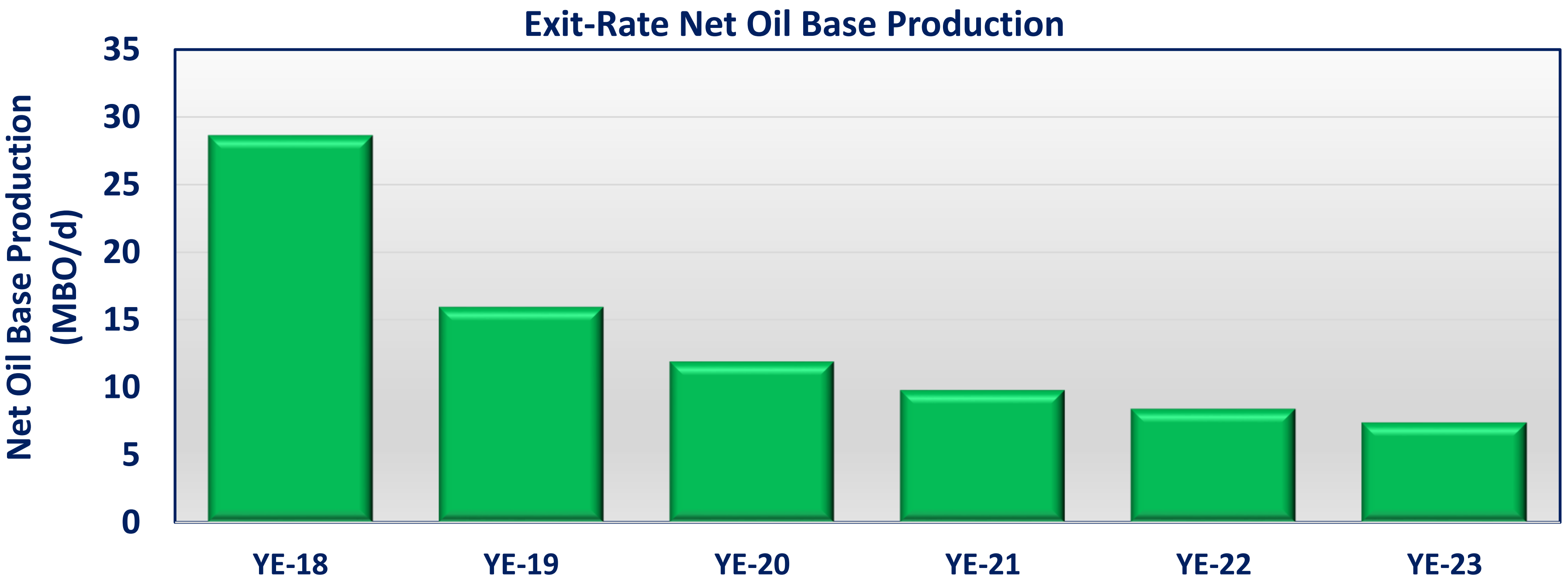
Note: Based on YE-18 3-stream proved reserves, prepared by Ryder Scott

YE-18 Oil PDP Reserves 5-Year Decline

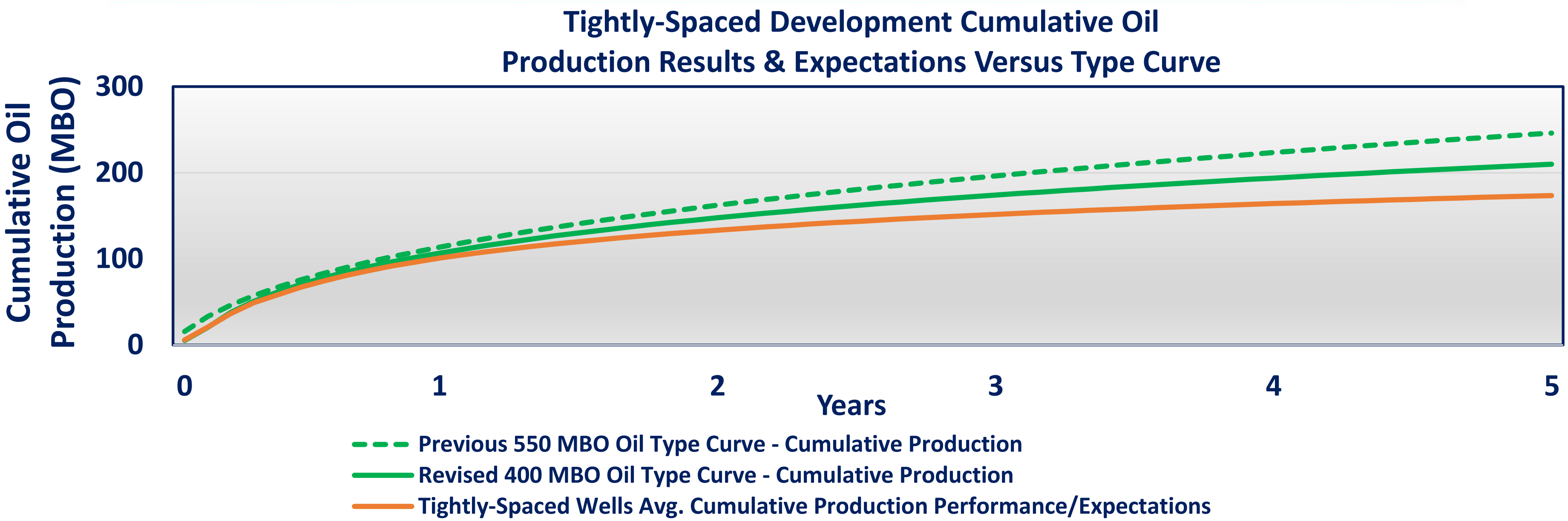


	Year 1	Year 2	Year 3	Year 4	Year 5
Decline Rate	-44%	-25%	-18%	-14%	-12%

Future oil decline rates expected to moderate with wider-spacing development strategy

Note: Based on YE-18 3-stream proved reserves, prepared by Ryder Scott

Revised Type Curve Improves Productivity Versus Tighter Wells



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3	26	84	31%
4	20	64	31%
5	16	53	30%
5-Year Cumulative	210	544	39%

47 Tightly-Spaced Wells: Avg. Production By Year			
Year	Oil (MBO)	Total (MBOE)	Oil Cut (%)
1	101	198	51%
2	33	116	28%
3	18	84	22%
4	13	62	20%
5	9	49	19%
5-Year Cumulative	174	509	34%

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Note: Includes the tightly-spaced 47 UWC/MWC development wells from the Sugg A 157/158, Lane Trust, Fuchs & Sugg D 104, Barbee-B and Sugg A 141/140 packages as of 2/10/2019, normalized to 10,000'
Table may not foot due to rounding

Development Strategy Focused on Wider Spacing

Formation	Development Zone	Wells per DSU	
		NAV/ Tight Spacing	ROR/ Wide Spacing
UWC	UW-AB	12 - 16 Wells	4 - 8 Wells
	UW-CD		
	UWE-MWA		
MWC	MW-B	12 - 16 Wells	4 - 8 Wells
	MW-C		
	MW-D		
LWC	LW-AB	6 - 8 Wells	4 Wells
	LW-C		
Cline	CLINE-AB	6 - 8 Wells	4 Wells
	CLINE-CD		
Total Well Count per DSU		36 - 48 Wells	16 - 24 Wells

Transitioning to wider-spacing development with 1Q-19 spuds, driving expected future improvements in capital efficiency and returns vs 2018

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Note: Excludes ABW, Canyon and Spraberry formations
Drilling spacing unit (DSU)

Transitional Year With a Commitment to Cash Flow Neutrality

Expected Activity	1Q-19	2Q-19	3Q-19	4Q-19
Continuous Drilling Activity	~ 3 rigs	~2 rigs	~1 rig	~1 rig
~28 gross well Completions <$54/BO WTI	~2.0 crews	~1.5 crews	0 crews	0 crews
~36 gross well Completions at $54/BO WTI	~2.0 crews	~1.5 crews	~0.5 crew	0 crews
Min. 36 gross well Completions >$54/BO WTI	~2.0 crews	~1.5 crews	Min. 0.5 crew & add'l as needed	

Strategic shift of varying operational cadence to match annual capital with operating cash flow

Any excess free cash flow could be utilized to complete additional wells, repurchase stock or reduce debt

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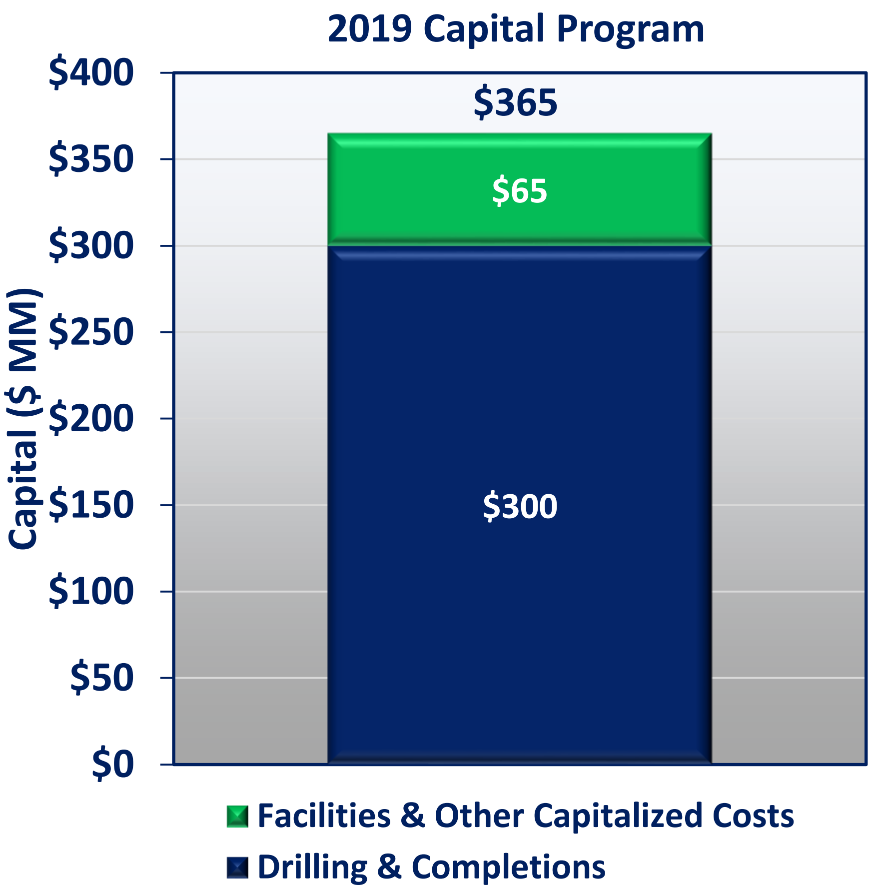
2019 Capital Program Demonstrates Flexibility & Discipline

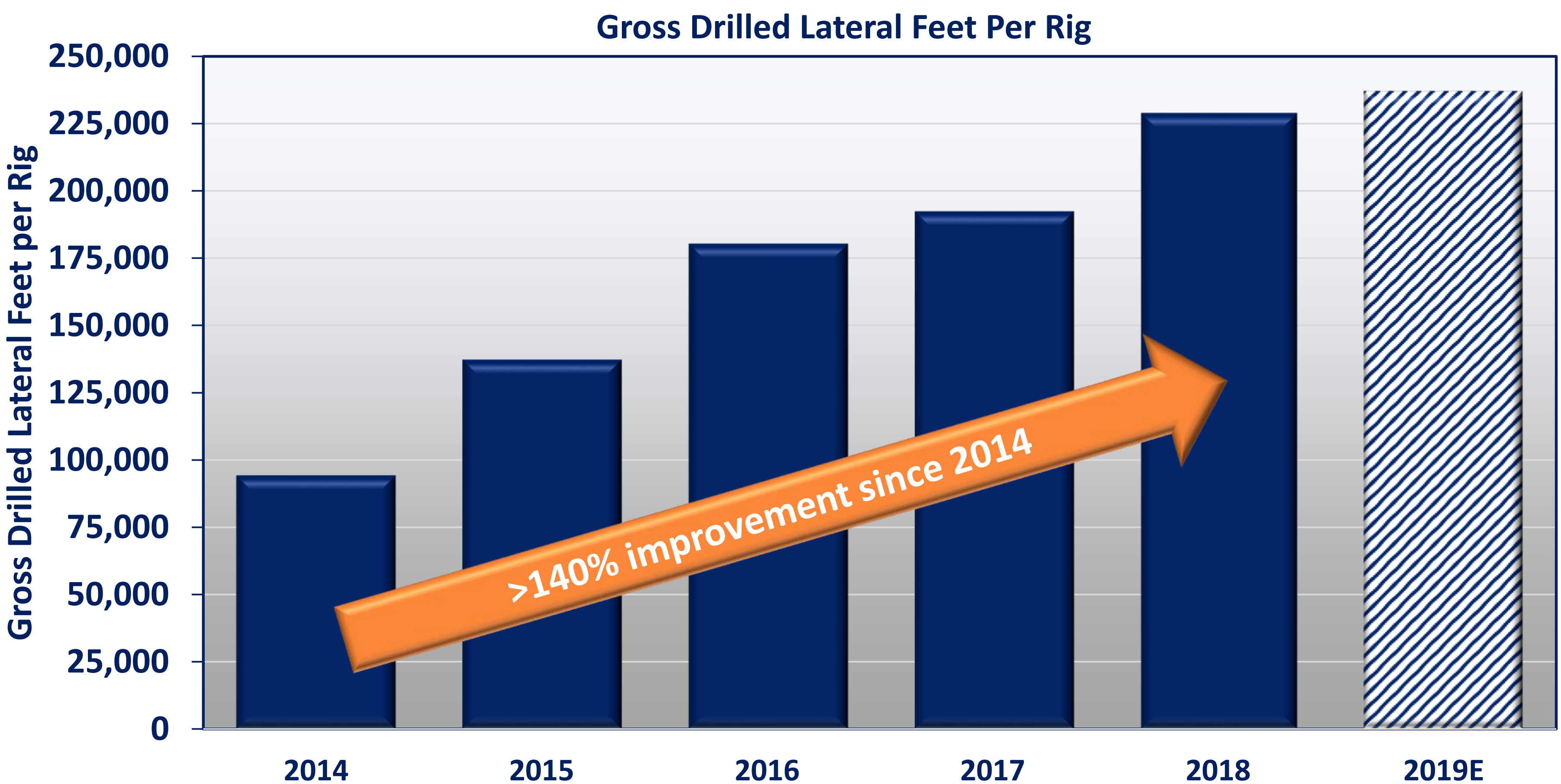


- YoY production expectations:
  - ~9% total production growth
  - ~5% oil decline
- Completing ~34 net wells
- ~11,400' avg. Hz lateral length
- ~95% avg. working interest

Expect to operate within cash flow, driven by front-loaded completions and a measured reduction in activity

Note: Excludes non-budgeted acquisitions
Capital program based on $54/BO WTI & $2.90/MMBtu HH

History of Improving Drilling Efficiencies



Continuous improvements are enabling us to do more with less

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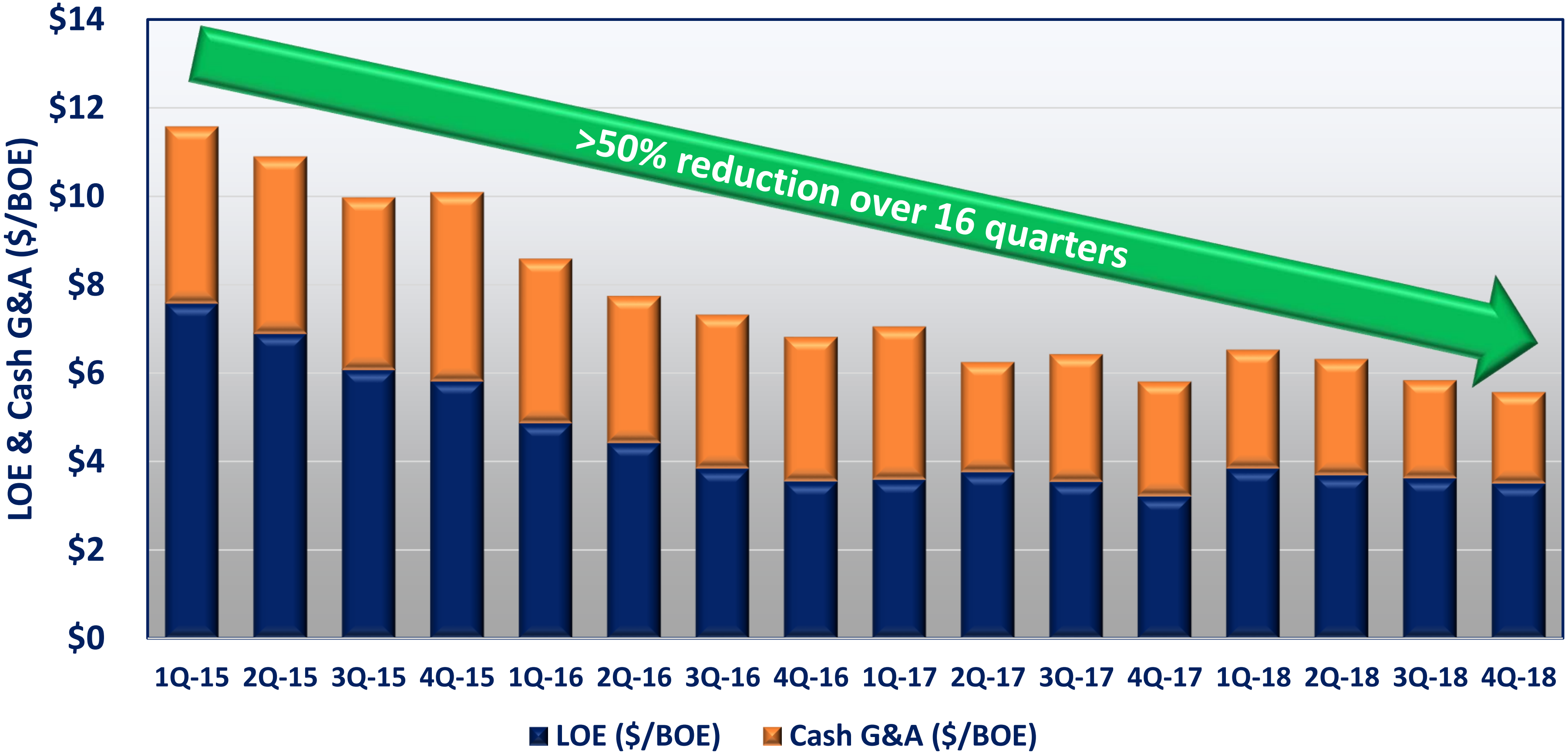
Note: 2019E as of 2/13/2019

Substantial Reduction in Controllable Cash Costs



Striving for further improvements in 2019

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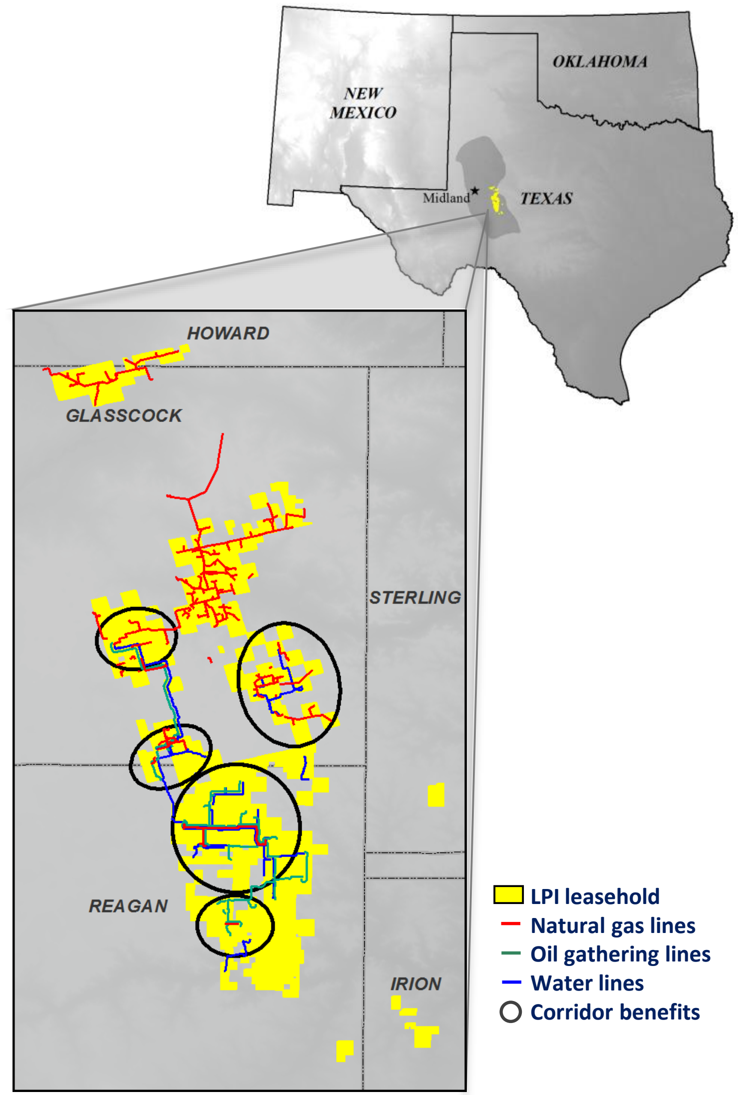
Prior Infrastructure Investments Helping to Reduce Operating Costs

Pipeline Infrastructure

- ~60 miles crude gathering
- ~110 miles water gathering/recycled distribution
- ~180 miles natural gas gathering & distribution
- >220,000 truckloads removed due to LMS infrastructure FY-18

~$32 MM

2018 net benefits from strategic infrastructure investments



Note: Maps, acreage counts and statistics as of 12/31/18
Benefits defined as capital savings, LOE savings, price uplift and LMS net operating income

Redefined Development Strategy Translates to Increased Value

Development Strategy

wider-spacing development + measured growth

- **Reduced future oil decline rates**
- **Cash flow neutrality**
- **Increased ROR vs. tighter-spaced development**
- **Improved long-term capital efficiency**

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APPENDIX

1Q-19 Guidance

	1Q-19E
Production (MBOE/d)...	74.0
Crude oil production (MBbl/d)..	27.5
Price Realizations (pre-hedge):	
Crude oil (% of WTI)...	~90%
Natural gas liquids (% of WTI)..	~24%
Natural gas (% of Henry Hub)...	~34%
Operating Costs & Expenses:	
Lease operating expenses ($/BOE)..	$3.50
Midstream service expenses ($/BOE)...	$0.15
Transportation and marketing expenses ($/BOE)..	$0.80
Production and ad valorem taxes (% of oil, NGL and natural gas revenue)............................	6.50%
General and administrative expenses:	
Cash ($/BOE)..	$2.25
Non-cash stock-based compensation ($/BOE)..	$1.25
Depletion, depreciation and amortization ($/BOE)...	$9.30

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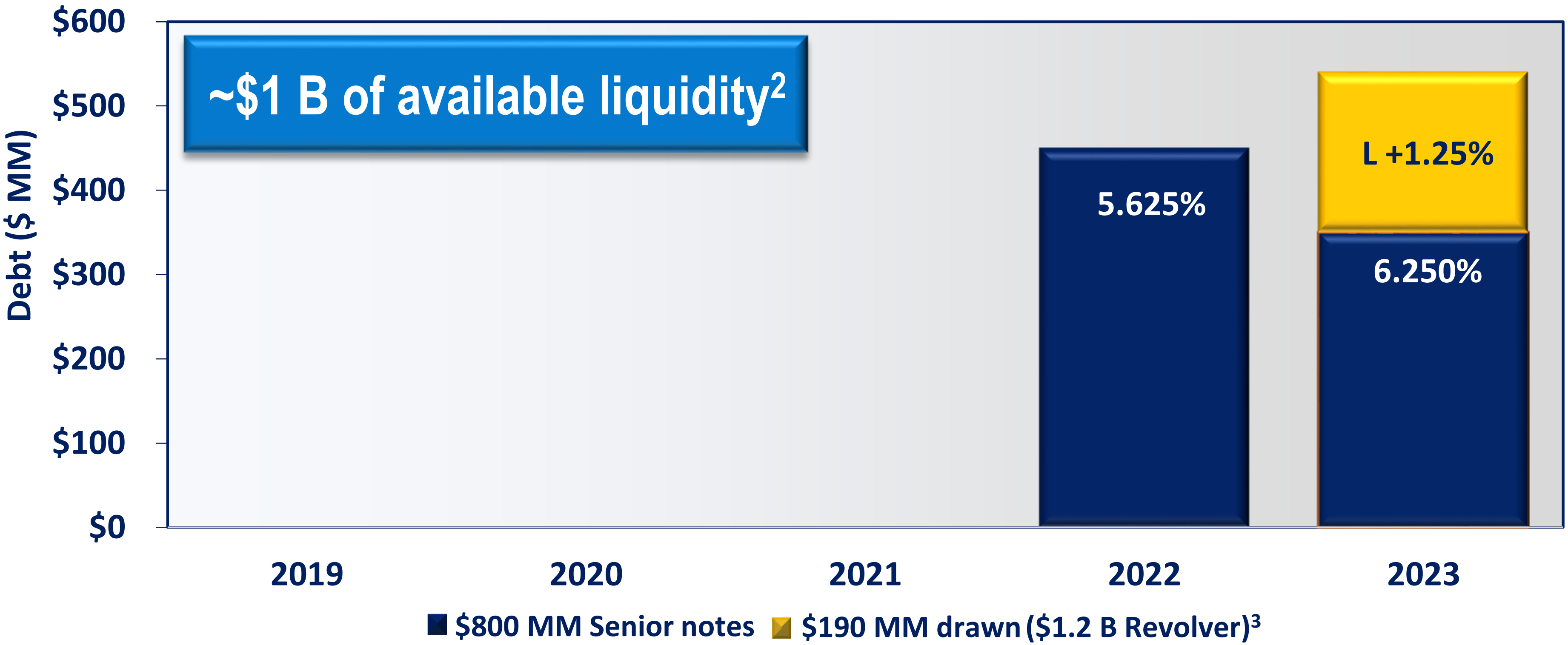
Maintaining A Strong Balance Sheet

~1.6x net debt to Adjusted EBITDA[1]

Debt Maturity Summary



[1]Net debt to Adjusted EBITDA is calculated as net debt as of 12/31/18 divided by FY-18 Adjusted EBITDA. Net debt as of 12/31/18 is calculated as the face value of debt of $990 MM, reduced by cash on hand of $45 MM. See Appendix for a reconciliation of Net Income to Adjusted EBITDA
[2]As of 12/31/18, with $1.2 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility, decreased by the $190 MM outstanding on the Revolver, increased by cash on hand of $45 MM and reduced by ~$14.7 MM outstanding letter of credit
[3]As of 12/31/18, with $1.2 B aggregate elected commitment in place under Fifth Amended and Restated Senior Secured Credit Facility

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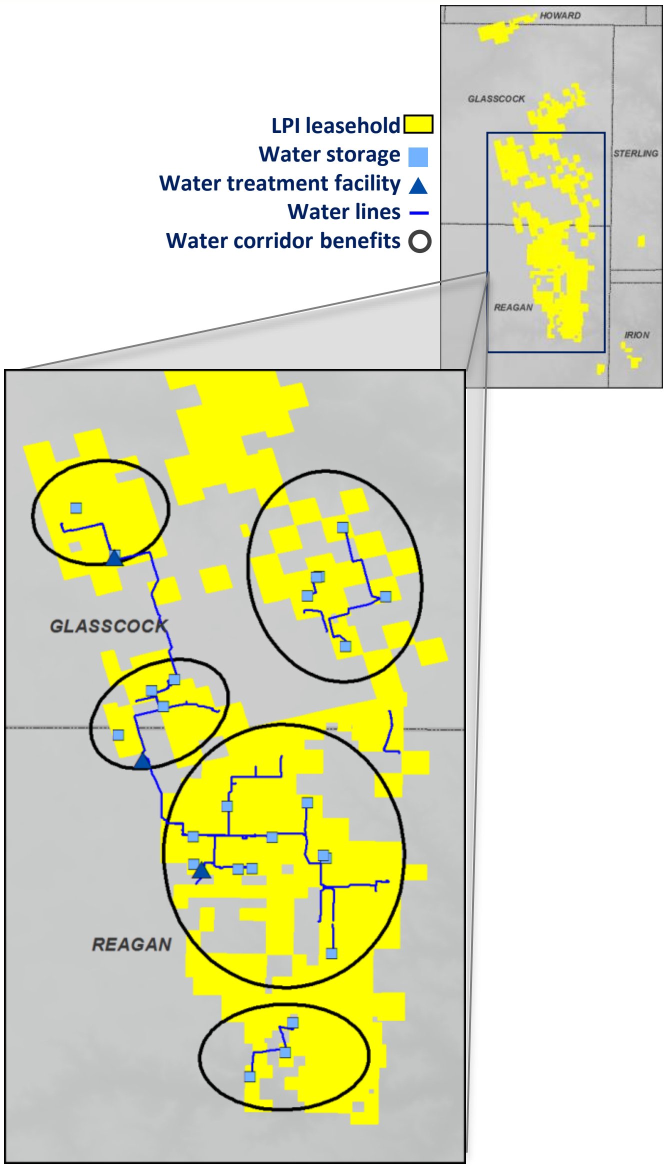
Significant Benefits Through Water Infrastructure Investments

Water Infrastructure

- ~110 miles of water gathering & distribution pipelines
- ~71% of produced water gathered by pipe and ~31% of produced water recycled in 2018
- 54 MBWPD recycling processing capacity
- 22.5 MMBW owned or contracted storage capacity

~$20 MM

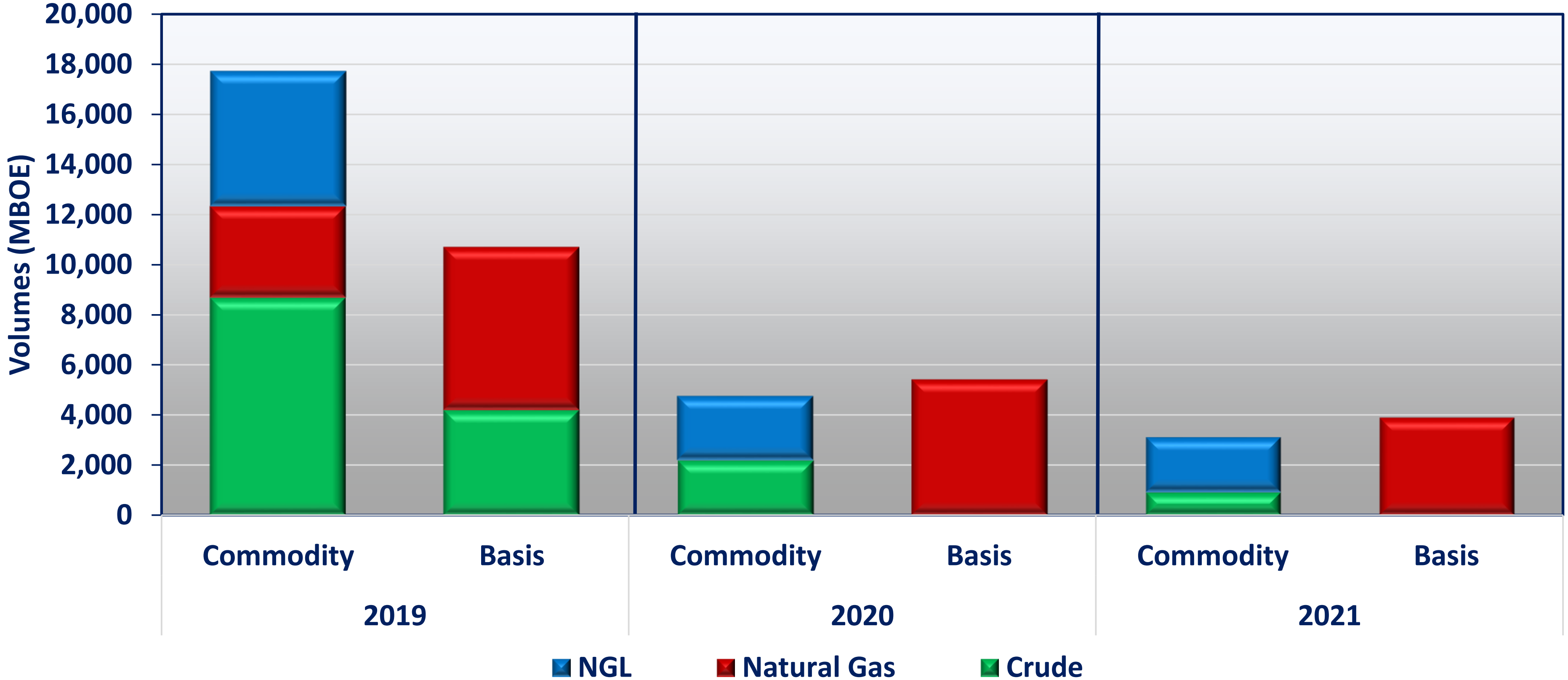
FY-18 net savings generated by LMS water infrastructure investments[1]



[1]Calculated utilizing a 95% WI & 74% NRI

Note: Statistics, estimates and maps as of 12/31/18

Consistent Financial Hedging Program



>90% **Cal-19 oil hedges are puts that retain unlimited upside to higher oil prices**

Note: Includes hedges executed through 2/13/2019

Oil, Natural Gas & Natural Gas Liquids Hedges

Hedge Product Summary	FY-19	FY-20	FY-21
Oil total floor volume (Bbl)	8,687,000	2,196,000	912,500
Oil wtd-avg floor price ($/Bbl)	$47.91	$47.27	$45.00
Oil total floor volume w. deferred premium (Bbl)	*4,745,000*		
Oil wtd-avg deferred premium price ($/Bbl)	*$3.21*		
Nat gas total floor volume (MMBtu)	21,900,000		
Nat gas wtd-avg floor price ($/MMBtu)	$3.23		
NGL total floor volume (Bbl)	5,388,100	2,562,000	2,202,775

Oil	FY-19	FY-20	FY-21
Puts			
Hedged volume (Bbl)	8,030,000	366,000	
Wtd-avg floor price ($/Bbl)	$47.45	$45.00	
Hedged Volume w. Deferred Premium (Bbl)	*4,745,000*		
Wtd-avg deferred premium price ($/Bbl)	*$3.21*		
Swaps			
Hedged volume (Bbl)	657,000	695,400	
Wtd-avg price ($/Bbl)	$53.45	$52.18	
Collars			
Hedged volume (Bbl)		1,134,600	912,500
Wtd-avg floor price ($/Bbl)		$45.00	$45.00
Wtd-avg ceiling price ($/Bbl)		$76.13	$71.00

Natural Gas - HH	FY-19	FY-20	FY-21
Swaps			
Hedged volume (MMBtu)	21,900,000		
Wtd-avg price ($/MMBtu)	$3.23		

Natural Gas Liquids	FY-19	FY-20	FY-21
Swaps - Ethane			
Hedged volume (Bbl)	2,233,000	366,000	912,500
Wtd-avg price ($/Bbl)	$14.21	$13.60	$12.01
Swaps - Propane			
Hedged volume (Bbl)	1,736,800	1,244,400	730,000
Wtd-avg price ($/Bbl)	$27.97	$26.58	$25.52
Swaps – Normal Butane			
Hedged volume (Bbl)	668,000	439,200	255,500
Wtd-avg price ($/Bbl)	$30.73	$28.69	$27.72
Swaps - Isobutane			
Hedged volume (Bbl)	167,000	109,800	67,525
Wtd-avg price ($/Bbl)	$31.08	$29.99	$28.79
Swaps - Natural Gasoline			
Hedged volume (Bbl)	583,300	402,600	237,250
Wtd-avg price ($/Bbl)	$45.83	$45.15	$44.31

Basis Swaps	FY-19	FY-20	FY-21
Mid/Cush			
Hedged volume (Bbl)	2,392,000		
Wtd-avg price ($/Bbl)	-$3.23		
Hou/Mid			
Hedged volume (Bbl)	1,810,000		
Wtd-avg price ($/Bbl)	$7.30		
Waha/HH			
Hedged volume (MMBtu)	39,055,000	32,574,000	23,360,000
Wtd-avg price ($/MMBtu)	-$1.51	-$0.76	-$0.47

Note: Open positions as of 12/31/2018, hedges executed through 2/13/19

See slide 23 for settlement details

Hedged volumes with deferred premiums outlined above are included in provided totals and are therefore not additive

Hedge Settlement Details

Other than the oil basis swaps, the Company's oil derivatives are settled based on the month's arithmetic average of the daily settlement prices for the NYMEX index price for the first nearby month of the West Texas Intermediate Light Sweet Crude Oil Futures Contract.

The oil basis swaps are settled based on the differential between the basis swaps' fixed differential price as compared to the differential between the arithmetic average of each day's index prices for the first nearby month on the pricing dates in each calculation period with the index prices being either (i) the Argus Americas Crude's West Texas Intermediate ("WTI") Midland-weighted average and the Cushing-based NYMEX West Texas Intermediate Light Sweet Crude Oil Futures Contract, (ii) the Argus Americas Crude's WTI Midland-weighted average and the WTI formula basis or (iii) the Argus Americas Crude's WTI Houston-weighted average and the WTI Midland-weighted average.

The Company's NGL derivatives are settled based on the month's arithmetic average of the daily average of the high and low OPIS index prices for Mont Belvieu Purity Ethane, TET and Non-TET Propane, Non-TET Normal Butane, Non-TET Isobutane and Non-TET Natural Gasoline.

Other than the natural gas basis swaps, the Company's natural gas derivatives are settled based on the Inside FERC index price for West Texas WAHA or the NYMEX index price for Henry Hub for the calculation period. The natural gas basis swaps are settled based on the differential between the basis swaps' fixed differential price as compared to the differential between the Inside FERC index price for West Texas WAHA and the NYMEX index price for Henry Hub for the calculation period.

Supplemental Non-GAAP Financial Measure

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that we define as net income or loss plus adjustments for depletion, depreciation and amortization, non-cash stock-based compensation, net, accretion expense, mark-to-market on derivatives, premiums paid for derivatives, interest expense, gains or losses on disposal of assets and other non-recurring income and expenses. Adjusted EBITDA provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, working capital movement or tax position. Adjusted EBITDA does not represent funds available for discretionary use because those funds are required for debt service, capital expenditures, working capital, income taxes, franchise taxes and other commitments and obligations. However, our management believes Adjusted EBITDA is useful to an investor in evaluating our operating performance because this measure:

- **is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods, the book value of assets, capital structure and the method by which assets were acquired, among other factors;**
- **helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and**
- **is used by our management for various purposes, including as a measure of operating performance, in presentations to our board of directors and as a basis for strategic planning and forecasting.**

There are significant limitations to the use of Adjusted EBITDA as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect our net income or loss, the lack of comparability of results of operations to different companies and the different methods of calculating Adjusted EBITDA reported by different companies. Our measurements of Adjusted EBITDA for financial reporting as compared to compliance under our debt agreements differ.

(in thousands, unaudited)	FY-18
Net income	$324,595
Plus:	
Income tax expense	4,249
Depletion, depreciation and amortization	212,677
Non-cash stock-based compensation, net	36,396
Accretion expense	4,472
Mark-to-market on derivatives:	
(Gain) loss on derivatives, net	(42,984)
Settlements received for matured derivatives, net	6,090
Premiums paid for derivatives	(20,335)
Interest expense	57,904
Loss on disposal of assets, net	5,798
Adjusted EBITDA	$588,862

Cash Margin Per BOE

($/BOE)[1]	2018	2017
Average sales price without derivatives[2]	**$32.50**	**$29.22**
Minus:		
Lease operating expenses	**$3.67**	**$3.53**
Production and ad valorem taxes	**$1.99**	**$1.78**
Transportation and marketing expenses	**$0.47**	**---**
Midstream service expenses	**$0.12**	**$0.19**
General and administrative – cash	**$2.40**	**$2.85**
Cash Margin	**$23.85**	**$20.87**

[1] The numbers presented above are based on actual results and are not calculated using rounded numbers
[2] Realized oil, NGL and natural gas prices are the actual prices received when control passes to the purchaser/customer adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.